TECHNICAL REVIEW DOCUMENT
for
OPERATING PERMIT 96OPJE143

to be issued to:

Trigen-Colorado Energy Corporation
Golden Facility
Jefferson County
Source ID 0590820

Michael E. Jensen
January 9, 2003

I. PURPOSE:

This document establishes the basis for decisions made regarding the Applicable Requirements, Emission Factors, Monitoring Plan and Compliance Status of Emission Units covered within the Operating Permit proposed for this site. It is designed for reference during review of the proposed permit by the EPA and during Public Comment. This narrative is intended only as an adjunct for the reviewer and has no legal standing. Conclusions in this document are based on information provided in the original application submittal of February 21, 1996, and supplemental Title V technical information submittals of October 7, 1999, February 18, April 28, and July 21, 2000, August 30, 2002, previous inspection reports, the technical documents submitted for the construction permits, as well as telephone contacts with the applicant.

On April 16, 1998, the Colorado Air Quality Control Commission directed the Division to implement new procedures regarding the use of short term emission and production/throughput limits on Construction Permits. These procedures are being directly implemented in all Operating Permits that had not started their Public Comment period as of April 16, 1998. All short term emission and production/throughput limits that appeared in the Construction Permits associated with this facility that are not required by a specific State or Federal standard or by the above referenced Division procedures have been deleted and all annual emission and production/throughput limits converted to a rolling twelve (12) month total. Note that, if applicable, appropriate modeling to demonstrate compliance with the National Ambient Air Quality Standards was conducted as part of the Construction Permit processing procedures. If required by this permit, portable monitoring results and/or EPA reference test method results will be multiplied by 8760 hours for comparison to annual emission limits unless there is a specific condition in the permit restricting the hours of operation.

This Operating Permit incorporated the following existing Construction Permits:

10JE660	11JE199	11JE305-1	11JE305-2	11JE305-3
13JE488	84JE375-1	84JE375-2	84JE375-3	92JE074-2

Any revisions made to the underlying construction permits associated with this facility made in conjunction with the processing of this Operating Permit application have been reviewed in accordance with the requirements of Regulation No. 3, Part B, Construction Permits, and have been found to meet all applicable substantive and procedural requirements. This Operating Permit incorporates and shall be considered to be a combined construction/operating permit for any such revision, and the permittee shall be allowed to operate under the revised conditions upon issuance of this Operating Permit without applying for a revision to this permit or for an additional or revised Construction Permit.

II. SOURCE DESCRIPTION:

Trigen purchased Coors Brewing Company's steam plant and associated equipment in 1995. The steam plant consists of five boilers and the associated equipment is for coal and ash handling. Steam is provided to Coors for process use. Excess steam is used to power turbine-driven electrical generators. Boilers 1 and 2 are equipped to use only natural gas and fuel oil for fuel. Boiler 3 has a spreader-stoker configuration equipped to use only coal as fuel. Boilers 4 and 5 are equipped to use coal as the primary fuel. Boiler 4 uses natural gas for the ignitors or as primary fuel. Fuel oil may be used as a backup fuel. Boiler 5 uses natural gas for the ignitors and start-up, and fuel oil is used for backup fuel. Ethanol, sludge from the Coors Company wastewater treatment plant, and on-site generated on-spec oil are used as auxiliary fuel with the coal in Boilers 4 and 5.

The coal used is received ready for feed to the boilers. No coal processing is performed on-site. Boilers 4 and 5 are equipped with pulverizers that introduce the coal directly into the fire zone. A cold start for Boiler 3 is accomplished by covering the grate with coal doused with fuel oil and ignited with a torch. Coal is fed intermittently until the boiler is on-line. The baghouse is in operation during the entire startup operation.

Boilers 1, 2 and 3 have grandfathered status for the requirement to have a Construction Permit. Boilers 4 and 5 are subject to Regulation No. 6 , Parts A and 40 CFR Part 60, New Source Performance Standard (NSPS) Subpart A - General Provisions and Subpart D - "Standards of Performance for Fossil-Fuel Fired Steam Generators for Which Construction is Commenced After August 17, 1971". NSPS Subpart D requires Boilers 4 and 5 to be equipped with continuous emission monitors for nitrogen oxides, sulfur dioxide, opacity and oxygen or carbon dioxide. Stack exhaust gas flow rate monitors were installed after the Title V application was prepared. The Division and EPA approved the use of the stack gas flow rate monitors in place of the continuous oxygen monitors previously used. The oxygen monitors are no longer required.

The transfer of the permits from Coors to Trigen provided the opportunity to officially update the existing permits for Boilers 4 and 5 to incorporate a number of changes that had developed since the original permits were issued. The permit modifications included the permit recognition of the use of the multiple fuels and the definition of the annual allowable emissions for sulfur dioxide and nitrogen oxides. In addition, the modified permit identifies mandatory reductions in the allowable limits for those two pollutants as a result of two separate actions agreed to by the previous permit owner, Coors Brewing Company. The two actions were a Settlement Agreement signed by Coors and the Division in February of 1994, and a State Implementation Plan (SIP) revision for particulate matter smaller than ten (10) microns (PM_{10}) requested by Coors in the fall of 1992, and signed into law in May 1995.

The Settlement Agreement contained a number of proposals to reduce the emissions of pollutants at the Brewery in response to a Notice of Violation issued to Coors for violation of State Regulations No. 3 and 7. Coors had been operating numerous sources of volatile organic compounds (VOC) (ethanol) without submitting APENs, obtaining permits, or meeting or addressing Reasonably Available Control Technology (RACT) requirements. As part of the settlement for the violation, Coors agreed to install a number of air pollution control systems to reduce VOC emissions by at least

69.5 tons per year. Subsequent to the agreement, Coors elected to duct collected VOC emissions to Boilers 4 and 5 for destruction in lieu of the installation of several of the individual air pollution control systems. In addition to the VOC reduction, Coors committed to a reduction of the allowable (permitted) sulfur dioxide emissions of 285 tons per year and the nitrogen oxides emissions of 285 tons per year.

The SIP revision was a proposal agreed to by Coors, the Division and the Air Quality Control Commission, whereby Coors could significantly increase emissions at their glass plant (now known as Rocky Mountain Bottle) in exchange for a reduction in allowable emissions at the brewery boilers. Sulfur dioxide emissions would be reduced by 135 tons per year and nitrogen oxide emissions would be reduced by 255 tons per year.

The combination of the two agreements required the sulfur dioxide emissions to be reduced by 420 tons per year, and the nitrogen oxides by 510 tons per year. Originally it was proposed the reductions would come from Boiler 4 only. Trigen requested and the Division approved the operating flexibility to take the reductions from either Boiler 4 or Boiler 5 or as a combination from both the boilers.

The existing Construction Permits for Boilers 4 and 5 had not established specific allowable annual emission limits from which the agreed upon reductions could be taken. The permit modifications provided annual limits based on the existing Construction Permit limits of 1.2 pounds per million Btu for sulfur dioxide and 0.7 pounds per million Btu for nitrogen oxides when burning coal. These fuel based permit limits were multiplied by the design rate of the boilers, in million Btu per hour, and 8760 potential operating hours per year to calculate the annual emissions limits. It should be noted that the design of Boiler 4 results in a design heat input rate specific to the type of fuel being combusted. The 360 million Btu per hour design rate for coal was selected because:

1) it was representative of the coal being burned as the primary fuel,
2) it was the design rate used in the PM10 SIP to calculate resultant Coors steam plant emissions after the agreed upon reductions were taken and made Federally enforceable,
3) it was the design rate identified in the existing Construction Permit, and
4) it was used to determine the short term limits set in the existing Construction Permit.

A recent change in the AP-42 emission factors resulted in an increase in the estimated VOC emissions when burning natural gas in Boiler #4. As a result of the emission factor change, the potential-to-emit for VOC emissions for natural gas is now greater than that for coal. The coal VOC emissions were the basis for the current permit limit. Trigen submitted a request to increase the VOC permit limit to recognize this change. A review found no need for any PSD or NSR review as a result of this increase in the VOC emissions.

The facility is located in Jefferson County in Golden, Colorado. There are no affected states within 50 miles of the facility. Rocky Mountain National Park and Eagles Nest Wilderness Area are Federal Class I designated areas within 100 kilometers.

Regulation No. 7 is incorporated in the Denver Metropolitan State Implementation Plan (SIP). During the processing of the Title V application and the preparation of this operating permit, changes in the ambient standards for ozone resulted in EPA removing the Denver metropolitan area from the ozone (VOC) non-attainment status. The Denver Metropolitan area is an attainment area, and the application of the Regulation No. 7 requirements to the cold solvent cleaner will remain unchanged since Regulation No. 7 will remain as part of the maintenance SIP.

This facility is located in an area designated as attainment for all criteria pollutants. It is categorized as a major stationary source (potential to emit of any criteria pollutant > 100 tons per year as a listed source) for carbon monoxide, sulfur dioxide, nitrogen oxides, particulate matter and particulate matter smaller than ten (10) microns (PM_{10}) for the Prevention of Significant Deterioration/New Source Review (PSD/NSR) provisions (Colorado Regulation No. 3, Part B, Section IV.D.3). The existing facility is currently not a PSD-permitted facility. Future modifications at this facility resulting in a significant net emissions increase (see Colorado Regulation No. 3, Part A, Section I.B.37 and 58) for any pollutant as listed in Colorado Regulation No. 3, Part A, Section I.B.58 or a modification which is major by itself may result in the application of the PSD review requirements.

There are currently no Maximum Achievable Control Technology (MACT) standards applicable to the power plant operations.

In accordance with agreements stated in an August 29, 2002 letter from Coors and an August 30, 2002 from Trigen to EPA Region VIII, the Coors Brewery operations (Colorado Facility Identification Code 0590006) and the Trigen Power Plant (Colorado Facility Identification Code 0590820) are to be considered as one source for the provisions of the Clean Air Act. This Operating Permit is associated with the following Coors Brewing Company Title V Operating Permits for purposes of determining applicability of Prevention of Significant Deterioration regulations:

Golden Business Units	96OPJE140	Can Manufacturing	96OPJE139

Facility-wide emissions are as follows:

		POTENTIAL TO EMIT, TONS PER YEAR						
		PM	PM_{10}	SO_2	NOx	VOC	CO	HAPs
B001 - 288 MMBtu/hr								
	NG	9.4	9.4	0.74	346.3	10.8	103.9	
	#2 FO	18.02	9.01	410.2	216.3	1.8	45.1	
B002 - 288 MMBtu/hr								
	NG	9.4	9.4	0.74	346.3	10.8	103.9	
	#2 FO	18.02	9.01	410.2	216.3	1.8	45.1	
B003 - 225 MMBtu/hr, Coal		2852.8	570.6	1512.83	380.4	2.16	216.1	
B004 - 360 MMBtu/hr,								
	Permit	158.0	158.0	1892.0	1104.0	19.21	88.30	
	Coal*	5268.55	1218.92	2650.05	639.36	4.86	39.55	
	NG	16.45	16.45	1.30	367.92	18.83	51.94	
	#2 FO	28.03	14.02	638.15	336.38	2.80	70.08	
B005 - 650 MMBtu/hr,								
	Permit	285.0	285.0	3416.0	1993.0	9.50	103.1	
	Coal*	11084.15	2556.71	5557.73	1346.16	10.02	82.62	
	NG	21.21	21.21	1.67	474.50	24.28	66.99	
	#2 FO	40.67	20.34	925.89	488.06	4.07	101.68	
M001/C004 - Rail car dumper to hoppers		51.6	51.6					
M001/C005 - Dumper to transfer conveyor								
M001/C006 - Conveyor to Unit 4 silos								
M001/C008 - Conveyor to Unit 5 silos		22.7	22.7					
M001/C007 - Conveyor to Unit 3 silos		0.015	0.015					
M002/C009 - 36-inch cyclone		37.5	37.5					
M002/C010 - 20-inch cyclone								
M002/C011 - baghouse								

	POTENTIAL TO EMIT, TONS PER YEAR						
	PM	PM_{10}	SO_2	NOx	VOC	CO	HAPs
M002/C012							
M003/C013 - 36-inch cyclone	10.2	10.2					
M003/C014 - 16-inch cyclone							
M003/C015 - baghouse							
M003/C017 - Bin vent	0.219	0.219					
M003/C016 - Flyash silo loadout	0.022	0.022					
E018 - General Motors diesel IC engine	2.45	2.45	2.28	33.3	2.63	7.36	
SIP & NOV Reductions			-420	-510			
TOTALS	3456	1157	7223	3693	55.0	622.6	
FACILITY 1998 ACTUAL EMISSIONS, TPY	19.93	18.63	2832.2	1605.8	11.8	202.3	60.1

Light shading values included in PTE Totals
* Includes sludge, ethanol & On-spec oil burned as auxiliary fuels with the coal

III. EMISSION SOURCES

The following sources are specifically regulated under terms and conditions of the Operating Permit for this site:

B001 – CD Model VU40 SN 17047, Front Fired, 288 MMBtu/hr
B002 - CE Model VU40 SN 17049, Front Fired, 288 MMBtu/hr

1. Applicable Requirements - These sources have grandfather status from the regulatory requirement to have Construction Permits. However, the sources are subject to the provisions of Regulation No. 1 which sets an opacity limit and fuel based limits for particulate and sulfur dioxide emissions. The sources also have grandfather status for Prevention of Significant Deterioration (PSD) applicability.

2. Emission Factors - Emissions from the boilers result from burning natural gas and No. 2 distillate. The primary criteria pollutants of concern are nitrogen oxides (NOx) and sulfur dioxides (SO_2). Standard factors from the AP-42 manual were selected for estimating the actual emissions. The sulfur dioxide emission factor incorporates the fuel oil sulfur content. In addition, the fuel oil heat and sulfur content are needed to determine compliance with the Regulation No. 1 sulfur dioxide limit. Since the heat and sulfur values may span a range of values, a fuel analysis is necessary to establish the actual values. Approval of emission factors for use with the boilers is necessary to the extent that accurate actual emissions are required to verify the need to submit Revised APENs to update the Division emission inventory, and for compliance determination and certification.

The boilers have the capability to burn fuel oil and natural gas simultaneously. There are no readily available published emission factors for this scenario. However, based on engineering judgment, the emissions should be representative of each fuel fraction. As such, total emissions under this scenario will be estimated as the sum of emissions from the fuel oil fraction and natural gas fraction. The following table presents the emission factors used for the Title V permit.

Pollutant	NG, lb/MMscf	#2 FO, lb/Mgallons
NOx	280	24
CO	84	5
VOC	8.7	0.2
PM	7.6	2
PM_{10}	7.6	50% * PM
SO_2	0.6	157 * %S

3. Monitoring Plan - Monitoring is based on tracking the amount of fuel burned by each boiler. Annually, the emissions are estimated from the fuel use in order to determine the emission fees to be paid.

The particulate emission limit for the boilers is 0.12 pounds per million Btu. The following calculations demonstrate that for the range of reasonably expected heat content values for natural gas and #2 diesel fuel, the design limits ensure compliance with the permit limit.

Natural Gas

$$\frac{7.6\ \text{lb}}{10^{6}\ \text{SCF}} \times \frac{\text{SCF}}{1064\ \text{Btu}} \ \text{X}\ \frac{10^{6}}{\text{MM}} = 0.007 \frac{\text{lb}}{\text{MMBtu}} < 0.12 \frac{\text{lb}}{\text{MMBtu}}$$

Fuel Oil

$$\frac{2\ \text{lb}}{10^{3}\ \text{gallon}} \times \frac{\text{gallon}}{138{,}000\ \text{Btu}} \times \frac{10^{6}}{\text{MM}} = 0.014 \frac{\text{lb}}{\text{MMBtu}} < 0.12 \frac{\text{lb}}{\text{MMBtu}}$$

4. Compliance Status - The Division accepts that the application information demonstrates that the facility was in compliance at the time Operating Permit application was prepared.

B003 - CE Model VU40 SN 17051, Coal Fired, Traveling Grate Spreader Stoker, Rated at 225 MMBtu/hr

1. Applicable Requirements - This source has grandfather status from the regulatory requirement to have a construction permit. However, the source is subject to the provisions of Regulation No. 1 which sets an opacity limit and fuel based limits for particulate and sulfur dioxide emissions. This source also has grandfather status for PSD applicability.

2. Emission Factors - Emissions from the boiler result from burning coal. No other fuel is used by the boiler. The primary criteria pollutants of concern are nitrogen oxides (NOx) and sulfur dioxides (SO_2). Standard factors from the AP-42 manual were selected for estimating the actual emissions. The sulfur dioxide emission factor incorporates the coal sulfur content. In addition, the coal heat and sulfur content are needed to determine compliance with the Regulation No. 1 sulfur dioxide limit. Since the heat and sulfur values may span a range of values, a fuel analysis is necessary to establish the actual values. Approval of emission factors for use with the boilers is necessary to the extent that accurate actual emissions are required to verify the need to submit Revised APENs to update the Division emission inventory, and for compliance determination and certification. The following table presents the emission factors used for the Title V permit.

	Coal Emissions, lb/ton			
Pollutant	Sub-bituminous	Bituminous	Lignite	Anthracite
NOx	8.8	11	5.8	3
CO	5	5	- - -	0.6
NMTOC	0.06	0.05	0.03	0.30
PM	66	66	8.0*%A	0.8*%A
PM_{10}	13.2	13.2	1.6*%A	
SO_2	35 * %S	38*%S	30*%S	39*%S
Lead	507lb/10^{12} Btu	507lb/10^{12} Btu	3.4*(C/A*PM)$^{0.80}$	0.0089

A= Ash S= Sulfur C = lead concentration in coal in ppmwt

3. Monitoring Plan - There is no regulatory requirement for this source to be equipped with continuous emission monitors. Monitoring is based on tracking the amount of fuel burned. Annually, the emissions are estimated from the fuel use in order to determine whether a revised APEN is required.

Particulate matter

The following calculation demonstrates that with the combination of the emission factor, a coal heat content of 22 MMBtu/ton and a 99 % control efficiency for the baghouse, the emission rate is well below the 0.12 lb/MMBtu limit.

$$\frac{66\ \text{lb}}{\text{ton}} \text{ x } (1.00 - 0.99) \text{ x } \frac{\text{ton}}{22\ \text{MMBtu}} = 0.03 \frac{\text{lb}}{\text{MMBtu}} < 0.12 \frac{\text{lb}}{\text{MMBtu}}$$

A reduction of the control efficiency to approximately 96% may result in an exceedance of the standard for a reasonable range of coal heat contents. However, the Division believes that other permit violations, such as opacity exceedances, would require corrective action before the baghouse performance deteriorated to this level.

Sulfur dioxide
The following calculation demonstrates that for a combination of a coal heat content of 22 MMBtu/ton and a typical sulfur content of 0.5%, the emission rate is well below the 1.8 lb/MMBtu limit.

$$\frac{35 \text{ X } 0.5 \text{ lb}}{\text{ton}} \text{ x } \frac{\text{ton}}{22 \text{ MMBtu}} = 0.795 \frac{\text{lb}}{\text{MMBtu}} < 1.8 \frac{\text{lb}}{\text{MMBtu}}$$

The following calculation demonstrates that Trigen needs to be mindful that a combination of a lower heat content and a high sulfur content (1.0 %) make it possible to exceed the 1.8 lb/MMBtu limit.

$$\frac{35 \text{ X } 1.0 \text{ lb}}{\text{ton}} \text{ x } \frac{\text{ton}}{18 \text{ MMBtu}} = 1.944 \frac{\text{lb}}{\text{MMBtu}}$$

4. Compliance Status - The Division accepts that the application information demonstrates that the facility was in compliance at the time Operating Permit application was prepared.

B004 - CE Model CE-VU40 SN 21321, Tangential Fired, Rated at 360 MMBtu/hr when burning coal

B005 - CE Model CE-VU40 SN 27576, Tangential Fired, Rated at 650 MMBtu/hr when burning coal

1. Applicable Requirements - The following attempts to organize and present the array of applicable requirements for these boilers.

State Regulations
These two boilers are subject to the provisions of Regulation No. 1 and Regulation No. 6, Part A.

New Source Performance Standards (NSPS)
These two boilers are subject to the provisions of 40 CFR Part 60 New Source Performance Standards (NSPS) Subpart A - General Provisions and Subpart D - Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction Is Commenced After August 17, 1971.

Prevention of Significant Deterioration (PSD)
The Title V Form 2000-300 for Boiler #4 notes the unit was placed in service in 1975. Sources that had not commenced construction prior to June 1, 1975, were required to obtain a PSD permit under the December 5, 1974, PSD provisions. The Division accepts that Boiler #4 had commenced construction prior to June 1, 1975.

The Title V Form 2000-300 for Boiler #5 notes the unit was placed in service in 1979. File information confirms Boiler #5 was placed in service in 1979, but did not reach full operating capacity until some time in 1980. Sources that obtained preconstruction permits before March 1, 1978 and commenced construction before March 19, 1979, were exempt from the

June 19, 1978 modification of the PSD provisions. Trigen provided a copy of the initial construction permit application transmittal letter dated February 10, 1977. The application transmittal letter date and the typical length of construction time necessary for a boiler of this size provide the basis for a reasonable presumption that construction commenced prior to March 19, 1979. While the June 19, 1978 PSD revisions do not apply, the December 5, 1974 and the November 3, 1977, revisions would apply because of the applicability date. These provisions address only 18 specific sources. Electric plants with more than a 1000 MMBtu/hour rating were included on the list, but fossil-fuel fired boilers were not. EPA and Coors worked together in reviewing the applicability requirements, and EPA determined that Boiler #5 would be exempt from the 1974 PSD provisions.

Title IV (Acid Rain Program)

The potential for this source to be subject to the provisions of Title IV (The Acid Rain Program) was reviewed since electricity may be generated from the steam produced. The file information regarding the capacity of the existing generators was confusing. The confusion was created by rating the boilers in terms of kiloWatt capacity. At first glance, it appeared each boiler was equipped with a turbine-driven generator, and the generators ranged in size from 22 megaWatts to 65 megaWatts. Additional review determined that three generators exist - two 10 megaWatt units and one 20 megaWatt unit. The steam from the operating boilers may be routed to the generator turbines or to process use in response to the demand.

40 CFR Part 72, Paragraph 72.6(b)(2) provided an exemption for "Any unit that commenced commercial operation before November 15, 1990, and that did not, as of November 15, 1990, and does not currently, serve a generator with a nameplate capacity of greater than 25 MWe." "Commenced commercial operation" was defined to mean to have begun to generate electricity for sale, including the sale of test generation. Prior to November 15, 1990, the facility was owned and operated by the Coors Brewery. The electricity was produced for the brewery use and not produced for sale.

Trigen purchased the Coor's energy systems on September 15, 1995. Trigen has taken the position that they are an independent source that sells electricity as they have contracts. Based on this Trigen claim, the energy systems are considered to have commenced commercial operation on September 15, 1995. However, Trigen qualifies for an exemption from this requirement because the largest generator (20 MWe) is not greater than 25 MWe.

40 CFR Part 72 Paragraph 72.6(b)(4)(i) exempts cogeneration facilities that supply equal to or less than 1/3 its potential electrical output capacity or equal to or less than 219,000 MWe-hrs actual electric output for sale on an annual basis to any utility power distribution. Trigen has taken the position that they are an independent source that may sell electricity as they have contracts, and their current electrical production is below the above limits. If at some future time the sale of electricity exceeds the limits noted above, this source becomes subject to the Title IV provisions and a Title IV application must be submitted in a timely manner.

Paragraph 72.6(a)(3)(i) makes a new utility unit subject to Title IV. Paragraph 72.7(a) provides a new unit exemption to any new utility unit that serves one or more generators with a total nameplate capacity of 25 MWe or less and burns only fuels with a sulfur content of 0.05 % or less by weight. Since the total nameplate rating for the three generators is 40 MWe and three of the boilers burn coal, the facility would not qualify under this exemption. However, Paragraph 72.6(a)(3) allows an exemption for cogeneration under paragraph 72.6(b) and thus the facility is not subject to the Title IV provisions.

State Implementation Plan & Settlement Agreement Emissions Reductions Requirements
As discussed in the beginning of this document, Boiler 4 and Boiler 5 are subject to the requirements established by the PM_{10} SIP and a Consent Order. The combination of these two emission reduction requirements results in the requirement for an annual reduction in the sulfur dioxide emissions of 420 tons and 510 tons per year for the nitrogen oxides emissions. The reductions may be demonstrated by either Boiler 4 or Boiler 5 or from reductions achieved by both boilers.

Multiple Permit Limits
The applicable requirements result in multiple fuel based limits for the sulfur dioxide, nitrogen oxides and particulate emissions. Trigen requested the particulate emission limits for the boilers be streamlined to identify only the most stringent emission limit. The most stringent limit is set by 40 CFR Part 60 §60.42(a)(1) at 0.1 pounds per million Btu.

Sulfur Dioxide:	
Fuel Oil:	
Both boilers	
Regulation No. 1, Part VI, Section A.3.b	0.8 pounds per million Btu
40 CFR Part 60 §60.43(a)(1)	0.80 pounds per million Btu
Coal	
Both boilers	
Regulation No. 1. Part VI, Section A.3.a.ii	1.2 pounds per million Btu
40 CFR Part 60 §60.43 (a) (2)	1.2 pounds per million Btu

Nitrogen Oxides	
Fuel Oil	
Both boilers	
40 CFR Part 60 §60.44(a)(2)	0.3 pounds per million Btu
Coal	
Both boilers	
40 CFR Part 60 §60.44(a)(3)	0.7 pounds per million Btu
Natural Gas	
Both boilers	
40 CFR Part 60 §60.44(a)(1)	0.2 pounds per million Btu

Particulate Matter
Fuel Oil
Coal
Natural Gas
Both boilers
40 CFR Part 60 §60.42 (a) (1) 0.1 pounds per million Btu

Coal
Boiler 4
Regulation No. 1, Section III, §A.1.b = $0.5(360)^{-0.26}$ = 0.11 pounds per million Btu

Boiler 5
Regulation No. 1, Section III, §A.1.c 0.1 pounds per million Btu

Fuel Oil
Boiler 4
Regulation No. 1, Section III, §A.1.b = $0.5(427)^{-0.26}$ = 0.10 pounds per million Btu

Boiler 5
Regulation No. 1, Section III, §A.1.c 0.1 pounds per million Btu

Natural Gas
Both boilers
Regulation No. 1, Section III, §A.1.c 0.1 pounds per million Btu

2. Emission Factors - The boiler emissions are created by the combustion of coal, fuel oil, or natural gas, or a mixture of these fuels , and also from the blending of sludge, ethanol and on-spec used oil with the coal. The criteria pollutants of concern are nitrogen oxides (NOx), sulfur dioxide (SO_2) and particulates (PM). Emissions will be determined from continuous emission monitors, stack tests or published factors from the AP-42 manual as appropriate. Some of the AP-42 emission factors contain a letter to recognize the impact of fuel quality on the emissions. An ‘A’ is used to incorporate the per cent ash content by weight, and ‘S’ is for the per cent sulfur content. A fuel sampling program is needed to determine these fuel properties since they may span a range of values.

The ignitors allow the boilers to burn coal and fuel oil, or coal and natural gas simultaneously. Also, sludge, on-spec oil and ethanol are mixed with the coal as auxiliary fuels. There are no readily available published emission factors to represent these scenarios when emissions must be calculated. However, based on engineering judgment, the emissions should be representative of each fuel fraction. As such, total emissions under these scenarios may be estimated as the sum of the emissions from the various fuel fractions.

Trigen noted that Construction Permit 11JE305, Condition 11 had a typographical error for the carbon monoxide emission factor. The correct value from AP-42 for fuel oil use is 5 pounds per thousand gallons of fuel oil, and not 5 pounds per MMBtu as shown in the permit. This error was corrected directly in the operating permit. Since the permit limits had been calculated correctly, no change to the carbon monoxide limit was necessary.

Trigen noted that Construction Permit 10JE660, Condition 11 had a typographical error for the carbon monoxide emission factor. The correct value from AP-42 for natural gas use is 40 pounds per million standard cubic feet of gas combusted, and not 40 pounds per MMBtu as shown in the permit. This error was corrected directly in the operating permit. Since the permit limits had been calculated correctly, no change to the carbon monoxide limit was necessary. Trigen further noted that the natural gas emission factor for carbon monoxide is now 24 pounds per million standard cubic feet of gas combusted. Condition 13 sets a natural gas consumption limit of 4415 million standard cubic feet per year. This natural gas use limit results in an estimated 51.9 tons per year of carbon monoxide emissions. Trigen did not request any change in the permit limit. The combination of the natural gas use limit and the new emission factor will preclude exceeding the current permit limit. Trigen will report the estimated annual emissions based on the new emission factor.

At the time Construction Permit 10JE660 was prepared the AP-42 VOC emission factor for natural gas combustion was 1.7 pounds per million standard cubic feet of natural gas combusted. In the current version of AP-42 (March 1998), Table 1.4-2, provides a natural gas VOC emission factor of 5.5 pounds per million standard cubic feet. The table also provides a TOC emission factor of 11.0 pounds per million standard cubic feet and a methane emission factor of 2.3 pounds per million standard cubic feet. Trigen requested to estimate the VOC emissions as the TOC minus the methane or 11.0 - 2.3 = 8.7 pounds per million standard cubic feet. This is a more conservative VOC estimate because the difference includes other emissions in addition to VOC. Trigen requested the permit limit be modified to reflect this higher emission factor. The request resulted in an increase of the allowable VOC emissions from 5.3 to 18.8 tons per year, for an increase of 13.5 tons per year. However, the amount of the actual emissions did not change. This requested increase did not trigger any applicable requirements for additional reviews or new modeling. The use of the higher emission factor will result in an increase in the estimated annual emissions and the associated annual fees.

The following table presents the emission factors used in the Title V permit. The emission factors for propane were used for the ethanol emission factors.

Pollutant	#2 FO, lb/Mgallons	NG, lb/MMscf	Ethanol, lb/Mgallons	Waste Oil, lb/Mgallons
NOx	24	170	21	19
CO	5	24	3.6	5
VOC	0.2	8.7	0.4*	1.0
PM	2	7.6	0.6	64 * %A
PM_{10}	50% * PM	7.6	0.6	51% * %A
SO_2	157 * %S	0.6	0.09 * %S	147 * %S

* TOC - CH_4 = 0.6 - 0.2 = 0.4

	Coal Emissions, lb/ton			
Pollutant	Sub-bituminous	Bituminous	Lignite	Anthracite
NOx	8.4	15	13	18
CO	0.5	0.5	0.25	
NMTOC	0.06	0.06	0.04	
PM	10*%A	10*%A	6.5*%A	10*%A
PM_{10}	2.3*%A	2.3*%A	2.3*%A	2.3*%A
SO_2	35 * %S	38*%S	30*%S	39*%S
Lead	507lb/10^{12} Btu	507lb/10^{12} Btu	3.4*$(C/A*PM)^{0.80}$	

A= Ash S= Sulfur C = lead concentration in coal in ppmwt

3. Monitoring Plan - As required by NSPS Subpart D these boilers are equipped with continuous opacity monitors, nitrogen oxide and sulfur dioxide emission monitors and stack gas flow monitors. Regulation No. 1, Section VI §B.3 and 40 CFR Subpart D §60.45 require the provision of the continuous monitoring of oxygen or carbon dioxide in the stack gas. The boiler is equipped with a continuous emission monitor for oxygen. In a March 31, 1998, letter from the Division to Trigen, the Division stated it concurred that oxygen sensors would not be required to compute lb/MMBtu because the stack gas flow rate was now being continuously monitored. In a December 10, 2002, letter from EPA Region VIII to Trigen, the EPA stated that this alternative method meets the minimum requirements for compliance with the monitoring requirements of Subpart D of 40 CFR Part 60. The Division identified the following equation to be used to calculate compliance:

$[lb/MMBtu]_p$ = $(PPM*C_p*T_c*ACFM*60)/Fuel$

where:

$[lb/MMBtu]_p$ = emission of pollutant in lb/MMBtu

PPM = concentration of pollutant in parts per million

C_p = concentration conversion factor (wet and based on a 350EF stack temperature) to convert ppm to lb/ft3

for NOx, $C_p = 6.3054 \times 10^{-8}$

for SO_2, $C_p = 8.780 \times 10^{-8}$

ACFM = actual gas flow rate, ft^3/min

T_c = Temperature correction from 350EF base = $(460+350)/(T_s+460)$, where T_s = stack gas temperature inEF

Fuel = fuel input to the boiler in MMBtu/hr

Particulate matter

The following calculation demonstrates that for the combination of the emission factor, a coal heat content of 22 MMBtu/ton and a 99% control efficiency for the baghouse, the emission rate is well below the 0.12 lb/MMBtu limit.

$$\frac{10 \text{ X } 7 \text{ lb}}{\text{ton}} \text{ x } (1.00 - 0.99) \text{ x } \frac{\text{ton}}{22 \text{ MMBtu}} = 0.032 \frac{\text{lb}}{\text{MMBtu}} < 0.12 \frac{\text{lb}}{\text{MMBtu}}$$

Trigen needs to be mindful that small combinations of changes in the baghouse control efficiency and the coal heat value can easily result in an exceedance of the standard. A reduction of the control efficiency to slightly less than 97% may result in an exceedance of the standard for a reasonable range of coal heat contents.

Sulfur dioxide
The following calculation demonstrates that the combination of a coal heat content of 22 MMBtu/ton and a typical sulfur content of 0.5%, the emission rate is well below the 1.8 lb/MMBtu limit.

$$\frac{35\text{ X }0.5\text{ lb}}{\text{ton}}\ \text{x}\ \frac{\text{ton}}{22\text{ MMBtu}} = 0.795\,\frac{\text{lb}}{\text{MMBtu}} < 1.8\,\frac{\text{lb}}{\text{MMBtu}}$$

The following calculation demonstrates that the combination of a low coal heat content and a high sulfur content of 1.0%, it is possible to exceed the 1.8 lb/MMBtu limit.

$$\frac{35\text{ X }1.0\text{ lb}}{\text{ton}}\ \text{x}\ \frac{\text{ton}}{18\text{ MMBtu}} = 1.944\,\frac{\text{lb}}{\text{MMBtu}}$$

The calculations indicate it should not be difficult to maintain compliance, however, there is the possibility of a problem if diligence is not maintained.

4. Compliance Status - The Division accepts the application information demonstrates that the facility was in compliance at the time Operating Permit application was prepared.

Coal Handling

C008 - Coal conveyor to Unit 5 silos	**11JE305-2**
C005 - Dumper hopper to transfer conveyor	**11JE199**
C006 - Coal conveyor to Unit 4 silos	**11JE199**
M001- Coal conveyor to Unit 3 silos	**13JE488**
C004 - Rail car dumper to coal hoppers	**11JE199**

As the facility developed from two boilers to five boilers, the different construction steps resulted in new or modified construction permits being required for the coal and ash handling equipment.

1. Applicable Requirements - As noted in the box above, three Construction Permits established the applicable requirements for these sources. The Construction Permits included hourly limits for process rates and emissions. None of the hourly limits were based on a regulatory requirement and were not carried forward into the Operating Permit as per the policy discussed at the beginning of this document.

2. Emission Factors - After considering the possibility of the use of a composite emission factor for estimating the emissions, the Division elected to use the estimation procedure proposed in the Title V application. The emissions are to be estimated in accordance with the procedures set forth in AP-42, Section 13.2.4, (1/95). The calculations are to be available for Division review if requested. In reviewing the compliance determination the Division accepted the use of the following particulate matter removal efficiencies:

Car dump hopper capture efficiency -	50%
Car hopper fabric filter -	99%
Unit 3, Unit 4 & Unit 5 silo coal conveyor fabric filters -	99%

3. Monitoring Plan - Weigh belts are used to monitor the amount of coal provided to each coal-fired boiler. Determining compliance with some of the emissions limits for the boilers requires knowledge of the heat content of the coal being combusted. In addition, particulate emissions from the boilers and the ash handling operations are dependent on knowledge of the ash content of the coal. Since the coal is sampled when shipped to verify compliance with purchase contract specifications, this was considered the most logical location in the permit for the coal sampling and testing requirements.

4. Compliance Status - The Division accepts that the application information demonstrates that the facility was in compliance at the time the Operating Permit application was prepared.

Ash Handling

M002 - General ash handling	**11JE305-3**
M003 - Boiler 4 & 5 flyash collection	**84JE375-1**
Flyash silo loadout	**84JE375-2**
Flyash silo bin vent	**84JE375-3**

As the facility developed from two boilers to five boilers, the different construction steps resulted in new or modified construction permits being required for the coal and ash handling equipment.

1. Applicable Requirements - As noted in the box above, four Construction Permits established the applicable requirements for these sources. The Construction Permits included hourly limits for process rates and emissions. None of the hourly limits were based on a regulatory requirement and were not carried forward into the Operating Permit in accordance with the policy discussed at the beginning of this document.

2. Emission Factors - Some of the processes include several pieces of air pollution control equipment operated in series to reduce the emissions. The performance of each control device may have an impact on the performance of the downstream devices. After considering the possibility of the use of a composite emission factor for estimating the emissions, the Division elected to use the estimation procedure proposed in the Title V application. The emissions are to be estimated in accordance with the procedures set forth in AP-42, Section 13.2.4, (1/95). The calculations are to be available for Division review if requested. In reviewing the compliance determination the Division accepted the use of the following particulate matter removal efficiencies:

36" cyclone collecting flyash and bottom ash -	93%
20" cyclone collection flyash and bottom ash -	96%
16" cyclone collecting flyash -	96%
Cyclone air stream discharge fabric filter -	99.7%
General Ash Silo bin vent fabric filter -	99%
Fly Ash Silo bin vent fabric filter -	98.8%

3. Monitoring Plan - The monitoring requires tracking the amount of coal consumed and the ash content of the coal. From this information and assumptions for the control efficiencies achieved, the associated emissions are estimated for the various handling processes.

4. Compliance Status - The Division accepts that the application information demonstrates that the facility was in compliance at the time the Operating Permit application was prepared.

E018 - GM 250 HP Diesel Engine for Compressor

1. Applicable Requirements - The applicable requirements were established by Construction Permit 92JE074-2.

2. Emission Factors - Emissions from reciprocating engines are produced during the combustion process, and are dependent upon the air/fuel mixture, engine design specifications, and specific properties of the fuel being burned. The pollutants of concern are Nitrogen Oxides (NOx), Carbon Monoxide (CO), Sulfur Dioxide (SO_2) and Volatile Organic Compounds (VOC). Small quantities of Hazardous Air Pollutants (HAPs) are also emitted when combustion is incomplete. Approval of emission factors for use with the engine is necessary to the extent that accurate actual emissions are required to verify the need to submit Revised APENs to update the Division emission inventory, and for compliance determination and certification.

3. Monitoring Plan - The emissions are to be calculated based on the horsepower and operating hours of the engine. The emissions are to be calculated monthly to determine compliance with the annual (12-month rolling total) limit. A Revised APEN must be submitted to the Division if criteria emissions increase by more than 50 tons per year or 5%, whichever is less, compared to the latest APEN on file with the Division.

4. Compliance Status - The equipment at this site has been operating for an extended time. A current APEN reporting criteria emissions is on file with the Division. The Division accepts the compliance signature of the responsible official as evidence of compliance.

M004 - Cold solvent cleaner

1. Applicable Requirements - As noted in the beginning of the review, the Denver metropolitan ozone (VOC) non-attainment designation was recently removed by EPA and a new designation has not yet been established. As a result the cold solvent cleaner emissions remain subject to the Regulation No. 7 provisions until a new designation is established and the regulations and the State Implementation Plan (SIP) are changed. No emissions limits are established. The Regulation No. 7 work practices and equipment design requirements are used to limit the volatile organic compound emissions.

2. Emission Factors - No factors are required.

3. Monitoring Plan - The Operating Permit requires a specific annual certification that the equipment in use meets the design requirements of the Regulation No. 7 provisions. Certification of compliance with the work practice requirements will be made separately.

4. **Compliance Status** - The Division accepts the application information demonstrates that the facility was in compliance at the time Operating Permit application was prepared.

Alternate Operating Scenarios

No alternate operating scenarios were identified

Permit Shield

The intent of the permit shield is to provide limited protection in the event of an error in the evaluation of whether a regulation, or portion of a regulation applies. The permittee identifies the issue and presents its position. The Division reviews the position. If the Division and the permittee mutually agree on the position, the issue is recorded in the operating permit. If there is a disagreement on the position, the Division has reserved the right to make the final decision. If, at a later date, it is discovered that an error was made in the mutual decision, the source is protected from the non-compliance due to the error. However, the permittee must move rapidly to obtain compliance.

In the Title V application the applicable sections of the Federal and State regulations are identified for the sources. The shield request was granted and noted in the Operating Permit where a specific request for the shield was identified, justified and accepted by the Division. The shield was not granted where a blanket request lacked specific detail, the request was not justified, or the Division did not agree that shield protection could be applied.

Hazardous Air Pollutants

The hazardous air pollutants originate as a component cleaning solvents and paint used. Hazardous air pollutant emissions are estimated by using the mass balance approach of calculating the amount of materials used, and the emissions associated with their use.

Accidental Release Program – 112(r)

Section 112(r) of the Clean Air Act mandates a new federal focus on the prevention of chemical accidents. Sources subject to these provisions must develop and implement risk management programs that include hazard assessment, a prevention program, and an emergency response program. They must prepare and implement a Risk Management Plan (RMP) as specified in the Rule.

Based on the information provided by the applicant, this facility is not subject to the provisions of the Accidental Release Prevention Program (Section 112(r) of the Federal Clean Air Act).

Short Term Limits

As noted at the start of this review document, new procedures resulted in the removal of short term emission and production/throughput limits from Construction Permits. The short term limits replaced in the permits are summarized in the following table.

Construction Permit	Emission Point	NOx, lb/hr	PM & PM_{10} lb/hr	SO_2, lb,hr	VOC lb/hr	CO lb/hr	Process Rate
92JE074-2	General Motors diesel fired IC engine, 250 HP	7.70	0.55	0.51	0.62	1.70	
11JE199	Rail car dumper to Unit 4 silos		44.0				Coal - 300 ton/hr
11JE305-2	Coal conveyor to Unit 5 silos		43.1				Coal - 300 ton/hr
11JE305-3	General ash handling		10.3				Ash - 8.4 ton/hr
13JE488	Coal conveyor to Unit 3 silos		0.074				Coal - 300 ton/hr
84JE375-1	Boiler 4 & 5 flyash collection		2.8				Flyash - 8.4 ton/hr
84JE375-2	Flyash silo loadout		0.17				Flyash - 240 ton/hr
84JE375-3	Flyash silo bin vent		0.06				Flyash - 8.4 ton/hr

Miscellaneous

From time to time published emission factors are changed based on new or improved data. A logical concern is what happens if the use of the new emission factor in a calculation results in a source being out of compliance with a permit limit. For this operating permit, the emission factors or emission factor equations included in the permit are considered to be fixed until changed by the permit. Obviously factors dependent of the fuel sulfur content or heat content can not be fixed and will vary with the test results. The formula for determining the emission factors is, however, fixed. It is the responsibility of the permittee to be aware of changes in the factors The permittee must notify the Division, in writing, of any need to modify the permit requirements when there is an increase in the estimated emissions based on the new factors. Upon notification, the Division will work with the permittee to address the situation.